PRELIMINARY DETERMINATION AND STATEMENT OF BASIS
ON THE APPLICATION OF

CALVERT CITY POWER I, L.L.C.

TO CONSTRUCT AND OPERATE A GAS-FIRED (3) SIMPLE CYCLE COMBUSTION
TURBINE PEAKING STATION FOR ELECTRICITY PRODUCTION
TO BE LOCATED AT NEEDMORE ROAD NEAR CALVERT CITY, KENTUCKY

REVIEW AND ANALYSIS BY:
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DIVISION FOR AIR QUALITY
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1. EXECUTIVE SUMMARY

The Calvert City Power I, L.L.C, (Calvert City Power), is to include two Westinghouse 501FD and one Westinghouse 501F natural gas-fired combustion turbines which are to operate in simple cycle mode. Each turbine is to be equipped with its own exhaust stack. The proposed facility is to increase peak power supply and improve the reliability of the TVA electric grid in the Marshall County area, thereby helping to alleviate peak power shortages and curtailments which have significantly impacted existing and proposed industry in the area. The facility is to produce electricity during periods of peak electricity demand on a daily and seasonal basis. The power plant will have a nominal electric generating capacity of 540 megawatts (MWs). The plant is to be limited to operating 3500 hours per year or less. The proposed plant will be a major source as defined in Kentucky State Regulation 401 KAR 51:017 (40 CFR 52.21), Prevention of significant deterioration (PSD) of air quality, with emissions of nitrogen oxides and carbon monoxide regulated air pollutants in excess of 250 tons per year. Emissions of nitrogen oxides, carbon monoxide, sulfur dioxide, particulate, and particulate-10, are emitted in quantities greater than the PSD significant emission rates. Pursuant to Kentucky State Regulation 401 KAR 50:035, Permits, the source is required to obtain a federally-enforceable permit to construct and operate the proposed plant.

The plant does not belong to one of the 28 major source categories listed because gas turbines used without heat recovery, such as simple cycle peaking units, have been determined to fall outside of the 28-source category list. The potential emissions of nitrogen oxides and carbon monoxide from this plant are more than 250 tons per year, and potential emissions of sulfur dioxide, particulate, and particulate-10 are in excess of the significant net emission rates as presented in Regulation 401 KAR 51:017, Section 22. The source will be located in a county classified as “attainment” or “unclassified” for each of these pollutants pursuant to Regulation 401 KAR 51:010, Attainment status designations. Consequently, the proposed facility meets the definition of a major stationary source and is subject to evaluation and review under the provisions of the PSD regulation for all these pollutants. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under Title 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

This source is subject to Title V as well as PSD permitting. The Title V permitting procedures are within State Regulation 401 KAR 50:035, Permits. The Code of Federal Regulations, 40 CFR Part 70 is the federal regulatory authority for Title V permitting. Therefore, this permit represents the draft PSD/Title V permit and the preliminary determination is also provided as a statement of basis for the Title V permit. This review demonstrates that all regulatory requirements should be met and includes a draft permit which establishes the enforceability of all applicable requirements.

2. BACKGROUND

On February 15, 1999, the Division received a permit application to construct and operate the natural gas-fired simple cycle turbine peaking station for electricity generation from Calvert City Power I, L.L.C.

Additional information was requested on numerous occasions and received on April 5, 1999, April 29, 1999, June 1, 1999, June 7, 1999, June 23, 1999, July 6, 1999, July 12, 1999, and July 16, 1999.

The application was logged complete on July 16, 1999.

Information from the application is given and assumed.

3. EMISSIONS ANALYSIS

The proposed Calvert City Power plant will produce electricity during periods of peak demand. The electricity generation operations will consist of: three natural gas-fired simple cycle combustion turbines (approximately 180 MW each), a 9 MMBTU/hour natural gas-fired fuel heater to eliminate condensation of hydrocarbons in the natural gas, fugitive emission units due to valves, flanges, etc. from the fuel handling system, an emergency fire-water pump engine (to operate 26 hours per year except in emergencies) that is diesel-fired and small fuel storage tank. For a detailed description of the plant processes and expected emissions at each emissions point and emissions unit, please see Section 2, Section 3, and Appendix B of the application. Please reference the application for the hourly and annual emission rates and pollutant identification for each respective emissions unit. Notice however, that the company has agreed to a reduced annual cap on nitrogen oxides emissions of 700 tons per year, which is about 206 tons per year less than originally proposed. Notice also, that the company has agreed to a reduced annual cap on carbon monoxide emissions of 800 tons per year that takes into account the higher emission rates due to operation at other than the rated capacity output load. Emissions were based on the maximum rated capacity of the plant and 3500 hours per year of operating time for the turbines after controls or less, 3500 hours per year or less of operating time for the fuel gas heater, 26 hours per year for the fire-water pump diesel engine for testing purposes, and continuous operation for the fugitive volatile organic compounds emissions units (fuel handling system). The turbines' annual emissions in Table 3-1 of the application are calculated for ambient temperature of 57 degrees Fahrenheit and baseload conditions (rated capacity output).

4. REGULATORY REVIEW

This section presents a discussion on the air quality regulations applicable to this project. In some cases the emission limit or technology standard based on these regulations may be superseded by the BACT requirements which are more stringent under PSD (see Section 5, Best Available Control Technology Review); however, any specific testing, monitoring, record keeping, and reporting requirements contained in these regulations will still have to be met by the source in addition to any requirements under PSD.

The following regulations will apply to the proposed plant (please see the application for a detailed description of the plant and specific processes/units within the plant):

Regulation 401 KAR 60:330, Standards of performance for stationary gas turbines, incorporating by reference 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, for emissions units with a heat input at peak load equal to or greater than 10 MMBTU/hour for which construction commences after October 3, 1977, applies to each of the simple cycle gas-fired turbines. The Subpart GG, applying the heat rate for the proposed turbines, results in an applicable standard for nitrogen oxides emissions on the order of magnitude of 100 ppm (the company documents specifically the range of 102 and 121 ppm) on a dry basis, corrected to 15 percent oxygen. The proposed BACT is much less than this amount at 25 ppm by volume corrected to 15 percent oxygen and on a dry basis.

Subpart GG standard for sulfur dioxide is that no owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight. Proposed BACT for sulfur dioxide is consistent with the EPA RACT/BACT/LAER Clearinghouse for gas turbines which is exclusive firing of pipeline quality natural gas that is described by the applicant to meet the 0.8 percent by weight requirement for sulfur in the fuel.

Subpart GG requires that the owner or operator using water injection, the proposed BACT, to control nitrogen oxides emissions shall install and operate a continuous monitoring system to monitor and record fuel consumption and the ratio of water to fuel being fired in the turbine. The sulfur content of natural gas fuel must be monitored. In accordance with EPA guidance memo dated August 14, 1987 by John B. Rasnic, monitoring fuel nitrogen content can be waived for pipeline quality natural gas since there is no fuel bound nitrogen and since the free nitrogen does not contribute appreciably to nitrogen oxides emissions. Periods of excess emissions that must be reported are defined in 40 CFR 60.334(c). The permit provides the appropriate monitoring, testing, reporting, and record keeping requirement of Subpart GG. Nitrogen oxides continuous emission monitors (CEMs) are to be used in lieu of monitoring the water to fuel ratio. A performance test is required by Subpart GG for nitrogen oxides, and oxygen concentrations, and sulfur content. Please refer to 40 CFR 60.335 for further testing details. The permittee will have a continuous emission monitor (CEMs) for carbon monoxide as well. The permittee shall maintain records which indicate that natural gas is the sole fuel fired in the turbine for particulate/particulate-10 periodic monitoring.

Acid Rain regulations, 40 CFR 72 through 40 CFR 78 apply. This source is required to apply for a phase II acid rain permit. Part 75 requires continuous emission monitoring.

Regulation 401 KAR 51:017 (40 CFR 52.21), Prevention of significant deterioration of air quality, applies to the proposed plant which will be located in Marshall County which is currently designated as “attainment” or “unclassified” for each of these pollutants pursuant to Regulation 401 KAR 51:010, Attainment status designations and 40 CFR 81.318. The proposed plant has the potential to emit more than 250 tons per year of one or more regulated criteria pollutants. Total plant wide potential emissions of all criteria pollutants including fugitive emissions are:

Pollutant	**PTE * (tons per year)**	**Significant Emission Rate ** (tons per year)**
Nitrogen oxides	702	40
Carbon monoxide	801	100
Sulfur dioxide	57	40
Particulate	98	25
Particulate matter (PM_{10})	98	15
Volatile organic compounds	35	40
Lead	0.16	0.6

* PTE - Potential to emit, emissions for turbines calculated with 3500 hours/year or less operation, lead- from AP-42
** Significant emission rate as given in Regulation 401 KAR 51:017, Section 22.

As seen in the table above, the plant will be a major source for nitrogen oxides and carbon monoxide. The PSD review applies to every pollutant that the proposed plant will emit in significant quantities, i.e., in amounts that will exceed the respective significant net emission rate. As seen above, the plant will be subject to PSD review for nitrogen oxides, carbon monoxide, sulfur dioxide, particulate and particulate-10. For each of these pollutants, the applicant will have to perform a best available control technology (BACT) demonstration and an ambient air quality analysis. Each of these components of the PSD review process have been discussed in detail in the following sections.

5. BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Pursuant to Regulation 401 KAR 51:017, Section 9(1) and (2), a major stationary source subject to a PSD review shall meet the following requirements,

(a) The proposed source shall apply the best available control technology (BACT) for each pollutant that it will have the potential to emit in significant amounts.

(b) The proposed source shall meet each applicable emissions limitation under Title 401, KAR 50 to 65, and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63.

The proposed source will be a major source resulting in emissions of nitrogen oxides, carbon monoxide, sulfur dioxide, particulate, and particulate-10 that exceed the corresponding PSD net significant emission amounts. Therefore, each of these pollutants shall be subject to a BACT review.

Calvert City Power has presented in the permit application, a study of the best available control technology for each pollutant and each emissions unit in the proposed source. The Division has reviewed the proposed control technology in conjunction with information available in the U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database. A summary of the control technology determined to be the best available control technology for each pollutant and each emissions unit is presented below:

A. Simple Cycle Gas Combustion Turbines

EIS No.	Emissions Unit/Process	Pollutant	Best Available Control Technology	Emission Standard
01, 02, 03 (TB-1, TB-2, TB-3)	Gas Turbines Operation limitation: 3500 hour/year or less	NO_x	Water injection with Good combustion practices	25 ppm by volume at 15 % oxygen and on a dry basis or 0.1 lb/MMBTU
		CO	Good combustion control	30 ppmvd at 15 % oxygen for operation at rated capacity output (baseload); 90 ppmvd at 15 % oxygen at other operating loads
		SO_2	Low sulfur natural gas fuel	2.0 grains/100 SCF
		PM/PM_{10}	Natural gas as fuel/low ash fuel and good combustion control	19 lbs/hr (501FD) 18.1 lbs/hr (501F)

B. Diesel Emergency Fire-Water Pump/Engine

EIS No.	Emissions Unit/Process	Pollutant	Best Available Control Technology	Emission Standard
05 (--)	Diesel Emergency Fire-Water Pump/Engine Operation limitation: 30 minutes operation in any given hour once a week except during emergencies	NO_x	Good combustion control/ Good operating practices	6.60 lbs/hour
		CO	Good combustion control	1.80 lbs/hour
		SO_2	Use of low sulfur fuel (0.05 wt. %)/ Good combustion control	0.05 wt. % sulfur in fuel/ 0.13 lbs/hour
		PM/PM_{10}	Use of low ash fuel/Use of low sulfur (0.05 wt. %) transportation diesel fuel/ Good combustion control	1.10 lbs/hour

C. Natural Gas Heater

EIS No.	Emissions Unit/Process	Pollutant	Best Available Control Technology	Emission Standard
07 (--)	Natural Gas Heater Operation limitation: 3500 hours/year	NO_x	Low NO_x technology/ Good combustion control	0.90 lbs/hour
		CO	Good combustion control	0.45 lbs/hour
		SO_2	Low sulfur natural gas fuel/ Good combustion control	2.0 grains/100 SCF
		PM/PM_{10}	Natural gas as fuel/low ash fuel/ Good combustion control	0.09 lbs/hour

The permittee submitted a top-down Best Available Control Technology (BACT) analysis following the U.S. EPA guidance, “New Source Review Workshop Manual” (U.S. EPA, October 1990). The key steps involved with the top-down BACT process are as follows:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls considering economic, environmental, and energy impacts, and document results
5. Select BACT.

A. BACT for Simple Cycle Natural Gas-Fired Combustion Turbines

This project is being proposed as a simple cycle electrical peaking facility. A simple cycle peaking project is fundamentally different than “combined cycle” baseload power supply systems that represent the majority of listings in the EPA RACT/BACT/LAER Clearinghouse. The differences in these two types of power generation technology are discussed in the application Sections 5.2.1 and 5.2.2.

Basically, once base load power demands are met, a need still exists to supply additional power at certain times when base load requirements are exceeded by a short term peak power demand. This simple cycle electrical peaking facility meets this configuration to supply short term power needed. These simple cycle gas-fired combustion turbines must therefore be able to come on-line and supply this power quickly which involves a rapid, quick heat-up period.

Thermal stress from this rapid heat-up process subjects certain materials, as ceramics, to differential thermal expansion and will cause stress that with cycling may result in failure of equipment if enough time is not taken to bring the temperature up gradually. On a given day, the demand for peak power may be short requiring quick startup.

This rapid heat-up sequence for a peaking plant results in difficulties with applying various control technologies to this project. A distinction must be made between previous BACT decisions for combined cycle units and simple cycle units due to the differing nature of operation and lower exhaust temperatures associated with combined cycle applications. A discussion of the decisions and situations surrounding the BACT for this project follow.

NO_x

Nitrogen oxides are primarily formed in combustion processes in two ways: (1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal nitrogen oxides), and (2) the oxidation of nitrogen contained in the fuel (fuel nitrogen oxides). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen (EPA 1996); therefore, nitrogen oxides emissions from combustion turbines originate as thermal nitrogen oxides. The rate of formation of thermal nitrogen oxides is a function of residence time and free oxygen, and is exponential with peak flame temperature.

The permittee's application, page 5-20 (Table 5-5), has a list of recent nitrogen oxides BACT determinations for simple cycle combustion turbines taken from the BACT/RACT/LAER Clearinghouse. Appendix C of the application has a list of BACT determinations for all pollutants and all types of combustion turbines. The emission levels of nitrogen oxides range from as low as 5 ppm to as high as 77 ppm. The Division's review of recent permitting actions or applications under review in other states reveals BACT limitations of 5 - 30 ppm on gas and 42 ppm on oil for several. The permittee has shown several facilities that use oil and gas as fuel. The overall lb/MMBTU level of two Dynegy plants in North Carolina is 0.1. Two other facilities, Tenaska and Sonat, in Georgia also have a lb/MMBTU level of 0.1. Another Dynegy plant in North Carolina has a lb/MMBTU level of 0.12 and CP&L in North Carolina has a level of 0.2 lb/MMBTU. The Calvert City Power project is to emit at a level of 0.1 lb/MMBTU while burning strictly natural gas. The following discussion indicates the decision and situations surrounding BACT for this natural gas-fired simple cycle turbine project.

The first step in the top-down BACT approach is to identify all control technologies. Firstly, inherently lower emitting control processes for gas turbines include water/steam injection, and dry low nitrogen oxides combustors. A new technology, catalytic combustion (XONON tm) is also being offered for limited applications. Fuel restrictions can contribute to lowering emissions as well.

One function of the addition of inert diluent such as water or steam into the high temperature region of a combustor flame is to quench the flame temperature thereby reducing thermal nitrogen oxides. Another benefit of water/steam injection is to increase power output. For this size turbine, 25 ppm nitrogen oxides (0.1 lb/MMBTU) can be expected with water injection. Water injection is readily available for this project.

Low nitrogen oxides combustors that do not require steam or water injection are called dry low nitrogen oxides combustors. This technology at the 9-15 ppm performance level is only offered by General Electric for the specific class of turbines proposed for the Calvert City project. However, production of this turbine is sold out through 2001-2002. From the Division's discussions with GE, it is concluded that the permittee would have had to lock in a contract in June 1998 in order to have the turbines delivered in time for the startup in summer 2000. The permittee anticipated and ordered the turbines at sometime around December 1998. If a GE turbine had been contracted at this time, the delivery would not occur until approximately first quarter 2001 which puts the permittee over a year behind in this project. Therefore, low nitrogen oxides combustors at the 9-15 ppm range are concluded to be unavailable for this case. The <u>EPA New Source Review Workshop Manual</u> (October 1990), which provides the recommended guidance in processing BACT reviews, indicates that "a technology is considered available if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term." Considering the common sense meaning of "available", it is concluded that the dry low nitrogen oxides combustors at the 9-15 ppm range are not commercially available within the timeframe necessary for this project. The permittee has explained that the lowest guaranteed emission rate using dry low nitrogen oxides technology from other turbine manufacturers (ABB, Siemens, Rolls Royce, and Westinghouse) is 25 ppm. Similar projects in Florida and North Carolina verify this situation. The initial limit for a couple projects is 25 ppm because Westinghouse has not fully advanced its dry low nitrogen oxides technology at this time but is working towards attaining the 9-15 ppm level after 2001-2002. See the Lakeland project in Florida and the Dynegy project in North Carolina, a table of the Division's research on recent simple cycle nitrogen oxides BACT determinations in Appendix C.

Another inherently lower emitting nitrogen oxides control process is catalytic combustion. Catalytic combustion is an emerging technology that uses an oxidation catalyst within the individual combustors to have the fuel and air react on a catalytic surface while maintaining optimum operating conditions in the turbine, and hence lower nitrogen oxides emissions. This technology holds the promise of eventually being capable of reducing gas turbine nitrogen oxides emissions to 2-5 ppmv. Catalytica has conducted full-scale demonstrations with GE and as part of the Advanced Technology System program (Solar Turbines and Allison Engine Company) of the XONON tm catalytic combustion system for new turbines. The permittee has concluded that this technology is unavailable at this time and not technically feasible for Westinghouse turbines.

Other control methods, known as add-on control techniques have been widely applied to baseload combined-cycle systems to remove nitrogen oxides from the exhaust gas stream once formed. A discussion follows below.

Selective Catalytic Reduction (SCR) using ammonia as a reagent represents the state-of-the-art for combined cycle gas turbine nitrogen oxides removal at 2-2.5 ppm level. Conventional SCR uses a metal honeycomb or "foil" catalyst support structure and requires a HRSG to drop the flue gas temperatures to under 800 ºF. Because of the high exhaust temperature of a simple cycle turbine, conventional SCR is not technically feasible. Instead a high temperature zeolite based SCR system has been recently introduced for use on certain simple cycle turbines. Zeolite is a sodium alumina silicate ceramic material with a design operating temperature of about 1000 ºF. The Division is aware of only four projects in which SCR has been applied for a simple cycle turbine application. A summary of these projects is presented below:

<u>Hot SCR at Redding, CA facility:</u>

- GE Frame 5 gas-fired units, (2) 1996, (1) 1997
- (2) with Englehard catalyst, (1) with Norton catalyst
- No precooling necessary
- Exhaust temperature 905-950 ºF
- Turbine with highest operating hours starting to have degraded performance
- Ammonia slip gradually increasing
- Problems getting insulation in catalyst bed
- Turbine with most operating hours has only 550 hours
- Limitation 9 ppm nitrogen oxides at 15 % oxygen with 10 ppmv ammonia slip

Hot SCR at Sempra, CA facility:

- 5 MW Solar gas turbines
- 1 year of operating experience with catastrophic catalyst bed failure due to temperature changes in exhaust gas
- Catalyst crumbled due to temperature variation
- Englehard catalyst replaced failed Norton bed
- 8 ppm nitrogen oxides limit (steady state)
- 12 ppm nitrogen oxides limit (in transition)

Hot SCR at Carson Energy, CA facility:

- One simple cycle turbine
- 5 ppmvd nitrogen oxides limitation with 20 ppmvd ammonia slip
- 3300 hours of operation since 1995
- No problems meeting the 5 ppm nitrogen oxides or 20 ppmvd ammonia limitations
- Design temperature 900 °F but operates at 880 °F
- No degradation, no maintenance on catalyst

Hot SCR at Prepa, Puerto Rico facility:

- Three 83 MW oil-fired simple cycle turbines
- Limits in spinning reserve mode
- Steam injection with hot SCR
- 10 ppm nitrogen oxides emission limitation
- Permittee has information that the catalyst is not performing properly and Prepa is seeking to get the catalyst removed

As can be seen from the above very limited operating history of hot SCR, catalyst degradation and lack of performance is a problem at higher operating temperatures. The Calvert City Power project is expected to have steady state and transient exhaust temperatures as high as 1050 °F to 1160 °F, which is well above the exhaust temperatures of 900 °F to 1000 °F at facilities that have installed hot SCR to date. Even these facilities have limited success with catastrophic catalyst failure, degraded performance, and the necessity to increase toxic ammonia emissions. The Clean Air Technology Center (MD-12) document, Zeolite- A Versatile Air Pollutant Adsorber (EPA-456/F-98-004 July 1998), indicates an operating temperature of 1000° F on page 5. With the nature of peaking units, and the probability of uneven heating, it is questionable as to the performance of hot SCR technology for this project, as developed to date. It is clear than some type of heat exchanger or cooling mechanism is necessary for the exhaust gas and the company has documented that this will increase the startup time which will inhibit the functionality of these turbines for peaking purposes and result in power loss or an energy impact, and negative environmental impacts. The Division is not comfortable with the application of hot SCR technology to this project due to the problems in performance that have been documented at the above mentioned sites and the limited development of SCR for simple cycle peaking applications. However, the Division has included this technology as a possible control option and has not eliminated this technology based on technical feasibility. Therefore, this technology is included in the control hierarchy of technologies.

Another emerging add-on technology is called SCONOx tm, which also uses a low temperature add-on catalyst but operates without ammonia. This technology has shown promise during initial trials on a 35 MW GE LM2500 combined cycle installation in California. SCONOx tm offers the promise of reducing nitrogen oxides concentrations to approximately 2-3.5 ppmv in certain combined cycle turbine applications. SCONOx tm is still very new and has been demonstrated in a single combined cycle heat recovery steam generator application operating in the 300 °F temperature range. SCONOx has been licensed to ABB Environmental Systems, Inc. for commercialization in the large turbine market. According to ABB, SCONOx will not be made available for application to large combined cycle units for at least 12 months. The SCONOx adsorption catalyst has a maximum temperature of 700 °F which is even lower than the zeolite catalyst used in hot SCR. Like conventional SCR, SCONOx could not withstand the high temperatures of a simple cycle turbine (over 1000 °F). SCONOx is not a technically feasible control option for the simple-cycle Calvert City Power I, L.L.C. peaking project.

Another add-on catalytic reduction technology, Selective Noncatalytic Reduction (SNCR) has been used to control emissions from certain combustion process applications. SNCR requires a flue gas temperature in the range of 1300 to 2100 °F, with an optimum temperature between 1600 and 1800 °F (Fuel Tech, 1991 and EPA 1990, example #1 page B.62). The simple cycle combustion turbines for the proposed project have exhaust temperatures of approximately 1100 °F. Therefore, additional fuel combustion would be needed to achieve exhaust temperatures compatible with SNCR operation. This temperature restriction makes SNCR technically infeasible for the simple cycle peaking combustion turbines. Additionally, there are no listings of this technology being applied to combustion turbines found in the Division’s RBLC Clearinghouse search.

Another add-on control technology, Nonselective Catalytic Reduction (NSCR), has been used to control emissions from certain combustion process applications. NSCR is only effective in controlling certain fuel-rich reciprocating engine combustion emissions and requires the combustion gas to be nearly depleted of oxygen (less than 4 % by volume) to operate. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16 % oxygen in the exhaust), NSCR is not technically feasible for the turbines. In addition, there are no listings of this technology being applied to combustion turbines found in the Division’s RBLC Clearinghouse search.

The control technologies that are considered technically feasible are listed in the hierarchy table shown below:

Control Technology	**NO_x Emission Level * (ppmv)**
High Temperature SCR	5-9
Dry Low NO_x combustors **	9-25
Water/Steam Injection	25-42
* Values represent long term operating values ** GE is promising 9 ppm only for certain future 7FA's. Current lowest is 15 ppm (GE 7FA), 25 ppm for Westinghouse, ABB, RR, Seimens.	

This table shows that hot SCR represents the most stringent add-on control technology that could be applied for a first-of-a-kind application to this simple cycle turbine project. Dry low nitrogen oxide combustors and water/steam injection represent the next most stringent, technically feasible control technologies for simple cycle turbines. It should be noted that hot SCR is included in this hierarchy as technically feasible although there are limited results as far as the performance of this technology for simple cycle applications. Of the three facilities noted in California, catalyst beds have failed and "crumbled" after only a few hours of operation. Catalyst performance has also degraded due to blinding and masking of the catalyst due to entrainment of internal contaminants.

As discussed above, none of the facilities where hot SCR has been applied in the U.S. have a long history of operating success. The permittee indicates these units are all substantially smaller (5-64 MW) than the 180 MW-class Westinghouse 501F and 501FD turbines for Calvert City Power and none have apparently operated more than 3,300 hours. Reduction catalysts are divided into two groups: metal (lower temperature combined-cycle applications) and zeolite (higher operating temperature; sodium aluminum silicate ceramic). These temperatures are achieved within the heat recovery steam generator of combined cycle generation units but are well below the exit temperature of simple cycle units. Conventional SCR has been eliminated due to incompatibility with high exhaust temperatures of simple cycle turbines.

Zeolite is the only currently available SCR catalyst material the Division is aware of that may be applicable to the elevated flue gas temperatures associated with simple cycle peaking turbine installations. Zeolite has a temperature limitation of 1100 ℉ (Booth 1998). The shorter term temperature excursions and thermal stresses typical of rapid start-up of simple cycle applications and guarantee provisions makes it necessary for a dilution air or cooling system to protect the catalyst bed from catastrophic high temperature failure. The simple cycle peaking turbines being considered for the Calvert City project have steady state and transient exhaust temperatures in the range of 1050 ^oF to 1160 ^oF, which is at the upper limit of the zeolite catalyst. According to Englehard, sustained operation or short term transient operation over these temperatures could result in permanent catalyst damage. This would require premature replacement of the zeolite catalyst. Any over temperature condition or temperature spike would not satisfy design criteria and could void the catalyst guarantee. Thus, a precooling system has been assumed to be necessary upstream of the catalyst to drop the exhaust temperature by 100 to 200 ºF and ensure that the catalyst temperature limit is never exceeded. It should be noted that the three installations in the U.S. operated and noted to date all have turbine exhaust temperatures in the range of 900 ºF to 1000 ºF. This is lower than exhaust temperatures expected for Calvert City Power. Thus, if hot SCR were applied to the Calvert City Power turbines it would represent a first-of-its-kind application.

Finally the installation of hot SCR will limit the rapid start-up sequence necessary to fully respond to fluctuations in peak power demand. Long term equipment life of the turbine transition piece, catalyst bed and support system is dependent on limiting differential thermal expansion (rapid and uneven heating) during startup. Differential thermal expansion of certain materials causes internal stresses within the material that, with cycling may result in premature failure (as catalyst crumbling). The applicant has explained that thermal stress is commonly limited by limiting the rate of startup allowing "heat soaking" of the materials before going to full load. Since short-term emission rates during startup exceed emission rates at full load, there is an environmental benefit to minimizing startup duration.

<u>Environmental Impacts - Hot SCR</u>
It is estimated that as much as 37 tons per year of uncontrolled nitrogen oxide emissions could result due to extended startup times. The figure is for all three turbines, and compare startup time with SCR to startup time without SCR based on the application.

SCR manufacturers typically guarantee 10 ppm of unreacted ammonia emissions (ammonia slip) with hot SCR. To achieve high nitrogen oxides reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which necessarily results in ammonia slip. Thus, an emissions trade off between nitrogen oxides and ammonia occurs in high nitrogen oxides reduction applications. In addition, the increased degradation of the catalyst from exposure to high temperatures would require more ammonia in order to continuously meet a lower nitrogen oxides emission limitation such as 5 ppm.

A summary of potential environmental impacts associated with the use of hot SCR follows:

- High temperature SCR has extremely limited operating experience on natural gas fired-simple cycle peaking turbines. In fact, there are no such domestic installations larger than 64 MW according to the application. Two of the three smaller units with hot SCR have experienced failures and one of the facilities has to revise its nitrogen oxides limit upward to maintain operation. Any control system failure results in downtime with unexpected short term environmental impacts and permit limit violations. When the Calvert City Power plant is not operational due to a forced outage, its loss in power output will be made up by older, less efficient, and in most cases, higher polluting generators.

- Unreacted ammonia would be emitted to the atmosphere as ammonia slip. This is documented by the permittee on a worst case basis to be as high as 110 tons per year at a 10 ppm slip. Ammonia slip levels vary over the life of the catalyst. With a fresh catalyst, slip levels of only a few parts per million may be sufficient to maintain the permitted nitrogen oxides emission rate. As the catalyst ages or becomes masked or blinded, more ammonia and slip is required. Additionally, there are safety issues associated with the transportation, handling, and storage of aqueous ammonia. The storage of aqueous ammonia (which is substantially lower risk than for anhydrous ammonia) is regulated under OSHA regulations and Risk Management Planning (RMP) provisions of the Clean Air Act Section 112(r).

In conclusion, the use of hot SCR would result in negative collateral environmental impacts.

Economic Impacts - Hot SCR

The cost effectiveness was calculated for hot SCR for comparison with other technologies. Capital costs associated with supplying high temperature-zeolite SCR system for Westinghouse 501F and 501FD turbines were based on vendor quotations. SCR capital equipment costs included the vendor provided equipment cost as well as additional auxiliary costs that the vendor did not specify.

The turbines that meet the technical criteria for this project are supplied from the turbine manufacturers with a maximum, design baseline nitrogen oxides outlet concentration of 25 ppm. The company has said that there are no turbines reasonably available to Calvert City Power for use in this project that emit more than 25 ppm. The basic equipment cost for controlling nitrogen oxides from 25 ppm to 5 ppm is based on a cost quotation from Engelhard (see Appendix C of the permit application). The costs were scaled by the permittee based on any differences in flowrates. The Division has reviewed and accepted cost data (from previous submittal in April) that is lower than the most recent July cost data information. This information shows the equipment cost for SCR plus auxiliaries per Englehard is estimated at $3,300,000. The total capital investment, annualized cost, total tons per year nitrogen oxides estimated to be controlled, and cost effectiveness are shown in the table below. It should be noted that the baseline uncontrolled used for these cost effectiveness numbers start at a 25 ppm level because according to the EPA New Source Review Manual (1990), p. B.37, the baseline emissions rate represents a realistic scenario of upper bound uncontrolled emissions for the source. Baseline emissions are essentially uncontrolled emissions calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of adding post process emission controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for use of inherently lower polluting processes. The applicant has stated that the lowest emission level that these turbines for this project may be purchased with is a 25 ppm level. Therefore, the tons of nitrogen oxides estimated that may be controlled per year with hot SCR are calculated from the uncontrolled baseline level of 25 ppm since these turbines must be purchased at that emission level. This level of emission control is documented by the applicant to be inherent in the combustion turbine process.

Table 1

Item for SCR Cost Analysis	Westinghouse 501F	Westinghouse 501FD
Total Capital Investment ($)	8,201,700	8,201,700
Total Annualized Cost ($/yr)	4,997,700	5,070,100
Tons/year NO_x Controlled	190	185
Cost Effectiveness ($/Ton)	26,300	27,400

- Notice tons/year NO_x adjusted for 700 tons/year annual cap versus the proposal for 906 tons/year from the turbines. Cost effectiveness adjusted accordingly.

The above numbers, particularly the cost effectiveness numbers indicate that SCR is not economically feasible. Hot SCR is not a cost-effective technology to control nitrogen oxide emissions from this simple cycle turbine project.

Conclusion - Hot SCR
The applicant has included many submittals over the course of the review period, increasing cost data for hot SCR by as much as 50%. The applicant has also provided information about the ammonia slip levels expected to be encountered in the environmental impact of hot SCR. These numbers have been varied in the different submittals by approximately 50%. However, the Division is still concluding that hot SCR is not economically or environmentally feasible at this time based on the middle range cost numbers in the April information and environmental impacts previously discussed.

The Division concludes that the economic and environmental impacts discussed above regarding hot SCR, particularly the prohibitive cost, lack of fully developed performance of the technology for simple cycle applications especially for the high exhaust temperatures as for this project, and negative environmental issues particularly associated with ammonia, indicate that possible application of hot SCR to this project is eliminated.

Discussion - Dry Low Nitrogen Oxides Combustors

Dry low nitrogen oxides combustion control techniques reduce nitrogen oxides emissions without injecting water or steam (hence the term “dry”). These combustors are offered for certain model engines from most turbine manufacturers and development of this technology is ongoing. These combustors reduce internal combustion temperatures thereby reducing thermal nitrogen oxides formation.

Dry low nitrogen oxides combustion control techniques are capable of achieving emission rates from 9 ppm to 25 ppm. The GE Frame 7FA is the only turbine offered with an emission rate of 9 ppm whereas the other turbine manufacturers according to the applicant offer an emission rate of 25 ppm.

According to Westinghouse, if either the 501F or the 501FD were retrofitted with dry low nitrogen oxides combustors, the outlet nitrogen oxides concentration would be guaranteed at 25 ppm (the high end of the expected range).

EPA's RBLC Clearinghouse indicates dry low nitrogen oxides emission rates as low as 9 ppm for certain simple cycle permits. However, this level of control is not available for the Calvert City Power peaking project the applicant documents. These combustors at a 9 ppm level have only been offered for two combustion turbine engine models to date. The Seimens V84.2 turbine was the first to offer this level. This is an older turbine model with a lower firing temperature and obsolete heat rate by today's standards. Seimens has replaced this model with a higher firing temperature model with a 25 ppm emission rate. General Electric (GE) offers a dry low nitrogen oxides model GE7FA turbine with emission level of 9 ppmv.

This technology at the 9-15 ppm performance level appears to be only offered by General Electric for the specific class of turbines proposed for the Calvert City project. However, production of this turbine is sold out through 2001. From the Division's discussions with GE, it is concluded that the permittee would have had to lock in a contract in June 1998 in order to have the turbines delivered in time for the startup in summer 2000. The permittee anticipated and ordered the turbines at sometime around December 1998. If a GE turbine had been contracted at this time, the delivery would not occur until approximately first quarter 2001 which puts the permittee over a year behind in this project. Therefore, low nitrogen oxides combustors at the 9-15 ppm range are concluded to be unavailable for this case. The EPA New Source Review Workshop Manual (October 1990), which provides the recommended guidance in processing BACT reviews, indicates that "a technology is considered available if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term." Considering the common sense meaning of "available", it is concluded that the dry low nitrogen oxides combustors at the 9-15 ppm range are not commercially available within the timeframe necessary for this project. The permittee has explained that the lowest guaranteed emission rate using dry low nitrogen oxides technology from other turbine manufacturers (ABB, Siemens, Rolls Royce, and Westinghouse) is 25 ppm. Similar projects in Florida and North Carolina verify this situation. The initial limit for a couple projects is 25 ppm because Westinghouse has not fully advanced its dry low nitrogen oxides technology at this time but is working towards attaining the 9-15 ppm level after 2001-2002. See the Lakeland project in Florida and the Dynegy project in North Carolina, a table of the Division's research on recent simple cycle nitrogen oxides BACT determinations in Appendix C. Again, low nitrogen oxides combustors at the 9-15 ppm range are concluded to be unavailable for this project.

Proposed BACT for Nitrogen Oxides - 25 ppm Water Injection

In wet injection, water or steam is injected into the turbine combustion chamber. This technology has been demonstrated as an effective method of controlling nitrogen oxides emissions in numerous applications. The purpose of injecting water into the burner is to decrease the flame temperature.

Water to fuel ratios may vary to achieve acceptable nitrogen oxides reduction levels. Water or "wet" injection is capable of reducing nitrogen oxides emissions to 25 ppmvd corrected to 15 percent oxygen. Realizing that dry low nitrogen oxides combustors are only capable of achieving 25 ppmvd according to the applicant and Westinghouse when retrofitting to these Westinghouse turbines at this time, water injection is comparable to advanced dry low nitrogen oxides technology in its ability to reduce nitrogen oxides emissions to 25 ppm.

Selection of NO_x BACT

Calvert City Power proposes to implement nitrogen oxides BACT through use of water injection achieving 25 ppmvd at 15 % oxygen. The permittee also agrees to limit emissions annually to a level of 700 tons per year of nitrogen oxides. SCR is eliminated as discussed above due to economic and environmental impacts and possible performance problems, the low nitrogen oxides burners at the 9-15 ppm level are eliminated due to lack of availability, and the remaining option, water injection, is selected and represents BACT. While Westinghouse will guarantee an equivalent emission level of 25 ppmvd at 15 % oxygen for their dry low nitrogen oxides technology, it is not better performing than the proposed water injection and is not immediately available according to the applicant. In addition, water injection has a history of long-term performance. This justifies the selection of water injection with good combustion control as BACT for nitrogen oxides control at a level of 25 ppmvd at 15 % oxygen.

CO

Carbon monoxide is formed as a result of incomplete combustion of fuel. For carbon monoxide control, the permittee evaluated the available control technologies which are: high temperature catalytic oxidation and the front-end technique of good combustion control. The most stringent CO control level available for simple cycle gas turbines would be achieved with the use of a high temperature (zeolite based) oxidation catalyst system, which can remove approximately 80 percent of CO in the flue gas (Booth, 1998, Section 5.4.2.1).

The Division has reviewed the EPA BACT/RACT/LAER Clearinghouse for combustion turbines. Only approximately five cases since early 1990 are documented in the clearinghouse to have specified catalytic oxidation as BACT. The overwhelming majority of determinations specify good combustion practices/good combustion control and operation/proper design and in some cases no controls. The permittee has provided a clearinghouse search printout (Table 5-8, p. 5-30 of the application July 12, 1999 submittal. The Division's search recognizes 3 cases other than those listed in Table 5-8). For simple cycle gas combustion turbines, the printout shows 9 to 60 ppm range.

The high temperature oxidation catalyst is expected to yield a 2 to 6 ppm range of CO emissions. This technology converts the CO to CO_2. This technology may require premature replacement of the catalyst due to catalyst poisoning (when a substance reduces or destroys the activity of a catalyst) or damage resulting from prolonged exposure to excessive temperatures. The use of catalytic oxidation will limit this project's ability to provide peak power market demands because of extended startup times since the long term equipment life is dependent on limiting differential thermal expansion or rapid and uneven heating during startup, the permittee has explained. The startup time desired is between 20 to 30 minutes but use of the oxidation catalyst is expected to increase startup time by up to 1.5 hours. If the lost power output were made up in a traditional coal fired utility plant as much as 11 tons per year of additional NO_x, 252 tons per year of additional SO_2, and as much as 8663 additional tons per year of CO_2 could be emitted. Additionally, with use of the oxidation catalyst up to 37 tons per year of additional NO_x could be produced due to extended startup times.

The economic analyses provided for the CO oxidation catalyst are shown in Appendix C. The Division has reviewed and accepted cost data provided by the applicant in the April and July submittals. This information indicates the total capital investment costs, annualized costs, and overall cost effectiveness for CO emissions calculated by the permittee. The following table 2 summarizes the results of the overall cost effectiveness taking into consideration the overall annual cap on carbon monoxide emissions from all three turbines combined:

Table 2

Turbine Model	Overall Cost Effectiveness ($/ton)
Westinghouse 501FD	11,700
Westinghouse 501F	11,900

- The annualized cost is taken from the application, Appendix C. The tons per year controlled of carbon monoxide is determined from the 800 tpy annual cap divided by 3 for each turbine and multiplied by 0.8 for 80 % control efficiency of catalytic oxidation.

The Division has determined that the overall cost effectiveness numbers indicate that the application of high temperature catalytic oxidation for CO is not economically feasible.

Considering the potential environmental and energy impacts associated with extended startup times and the economic impact of oxidation catalyst technology, the Division agrees with the permittee’s elimination of this control technology.

The next most stringent level of control is the 30 ppmvd at 15 % oxygen of CO emissions with use of good combustion control for operation at rated capacity output load (baseload); and a level of 90 ppmvd at 15 % oxygen with use of good combustion control for operation at other operating loads. This level of control is documented as available and that it will not cause negative environmental impacts or operational impacts. This type of control is the most common in the BACT/LAER clearinghouse. Therefore, good combustion control is selected as BACT for CO emissions at a level of 30 ppmvd at 15 % oxygen while at rated capacity output load (baseload) or 90 ppmvd at 15 % oxygen while at other operating loads. During any three-hour period in which the unit is operated at both rated capacity output and less than rated capacity output, the carbon monoxide emission limit shall be based on the time-weighted average of 30 ppmvd and 90 ppmvd.

$\underline{SO_2}$

Sulfur dioxide is formed exclusively from the oxidation of the sulfur present in the natural gas fuel. The emission rate is a function of the sulfur content of the fuel since virtually all the sulfur in the fuel is converted to SO_2. The simple cycle combustion turbines will fire exclusively pipeline quality natural gas.

The Division has reviewed the EPA BACT/RACT/LAER clearinghouse and natural gas/low sulfur fuel is the main control technique used for reducing SO_2 emissions. One case documented engine design and use of natural gas as fuel. The applicant's review indicates use of low sulfur fuel as the only available SO_2 control method to be selected as BACT in previous determinations for gas turbines.

This indicates that exclusive firing of low sulfur pipeline quality natural gas is the most stringent SO_2 control technique that has been demonstrated to be feasible for gas turbine applications. Therefore, the Division agrees with the permittee's BACT determination for SO_2, which is use of low sulfur fuel/natural gas as fuel with a sulfur content of 2 grains/100 scf.

$\underline{PM/PM_{10}}$

Particulate emissions from natural gas combustion consist of inert contaminants in natural gas, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, particulate of carbon and hydrocarbons resulting from incomplete combustion, and condensibles. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions. Trace metals may be emitted from natural gas combustion and are discussed in this section because these form a part of the particulate emissions. The Division has checked the lead emissions based on an AP-42 factor and these are calculated at less than the net significant emission rate.

When the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA as the permittee documents, recognized that "particulate emissions from stationary gas turbines are minimal." EPA noted that particulate control devices are not typically installed on gas turbines and that the cost of installing these is prohibitive (U.S. EPA September 1977) as the permittee documents. Performance standards for particulate control of stationary gas turbines were, thus, not proposed or promulgated.

The Division has reviewed the EPA BACT/RACT/LAER clearinghouse for gas turbines for particulate control BACT determinations. The Division has found the specification of natural gas as fuel to be the main control technique for particulates. Several listings are for low sulfur fuel, natural gas as fuel, maintain the turbines in good working order, good combustion practice and operation, clean burning fuels, and no controls.

Therefore, as the permittee also explains on p. 5-34 to 5-35 of the July 12, 1999 submittal, the use of natural gas as fuel and good combustion control is concluded to represent BACT for particulate emissions from the simple cycle gas-fired combustion turbines. This amounts to a specification of 18.1 lbs/hour particulate emission limitation for the 501F turbine, and 19 lbs/hour for the 501FD turbines (2).

B. Diesel Emergency Fire-Water Pump/Engine

The permittee has submitted modeling analysis of the ambient impact predicted to occur due to the diesel engine. The permittee has indicated that this engine will only operate for 30 minutes in a given hour once per week except during emergency situations. Because the ambient impact was shown to be less than the significant impact levels, including this engine at this limited operation, this operational limitation has been made part of the permit. This limitation is required to ensure the air quality impact is below the significant impact level and a full impact analysis will be required to increase this limit. This limit is thus included as part of the BACT analysis of emission levels.

NO_x

The permittee documents that EPA's draft Alternative Control Technology (ACT) document for reciprocating engines (EPA, 1996) lists add-on techniques such as SCR as well as combustion control techniques such as ignition retard for NO_x control from diesel engines. The ACT concludes that add-on controls are not cost effective for "emergency diesel engines" that typically operate less than 500 hours/year. Considering the environmental impact of the emission rate of 6.60 lbs/hour and 0.086 tons/year since the pump is only to be operated 30 minutes during any given hour once per week except for emergencies, the Division has accepted the permittee's proposal of good combustion control/good operating practices with a limit of 6.6 lbs/hour to be BACT for NO_x with the operational restriction of 30 minutes per any given hour once per week except for emergencies.

CO

The permittee documents that add-on controls for CO emissions have never been applied to emergency diesel engines that operate less than 500 hours/year. The permittee indicates that emissions are far too low for the control technology to be cost effective. The Division has therefore accepted good combustion control to represent BACT for the proposal, with a CO emission limitation of 1.80 lbs/hour (amounting to 0.023 tons/year given the limit of 30 minutes operation per any given hour once per week except during emergencies).

SO_2

The permittee maintains that the only control technique available for diesel engines that operate less than 500 hours/year is the use of low sulfur fuel. The use of low sulfur diesel fuel, 0.05 wt. % sulfur, thus represents BACT for SO_2 from the diesel fire-water pump with an emission level of 0.13 lbs/hour and the operational limitation on hours of operation (amounting to 0.002 tons/year).

PM/PM_{10}

The most stringent particulate control method for a diesel engine that operates 500 hours/year or less is documented by the permittee to be the use of a low ash fuel/low sulfur transportation diesel fuel. Proper combustion control and the firing of fuels with negligible or zero ash content (such as very low sulfur 0.05% transportation diesel for the fire-water pump) is the predominant control method listed in the clearinghouse.

The Division agrees with the permittee's determination because this engine is for emergency purposes and permitted to operate for 30 minutes during any given hour once per week. Considering the environmental impact of the emission rate of 1.10 lbs/hour (and 0.014 tons/year with the limited number of hours of operation) the Division has accepted the permittee's proposal of use of a low ash/use of a low sulfur fuel with good combustion control and a limit of 1.1 lbs/hour to be BACT for PM/PM_{10}.

C. Natural Gas Heater

NO_x

The permittee documents that BACT has traditionally required good combustion control practices on natural gas heaters that have a maximum heat input of less than 10 MMBTU/hour, particularly for equipment that only operates for a small fraction of the year. Calvert City Power will install a natural gas heater that will include low-NO_x technology to fire natural gas fuel, which represents BACT with the good combustion control.

The Division agrees with the proposal since the environmental impact of the 0.90 lbs/hour for 3500 hours/year is minimal. Thus, low-NO_x technology/good combustion control with natural gas-firing is representative of BACT for the natural gas heater at 0.90 lbs/hour (amounting to 1.58 tons/year).

CO

The permittee documents that add on controls for CO emissions have never been applied to small natural gas-fired heaters with maximum heat inputs less than 10 MMBTU/hour, especially those operating only for a fraction of the year. Good combustion control, the permittee explains, is concluded to represent BACT for the Calvert City Power natural gas heater.

Considering the limited environmental impact of the CO emissions from the natural gas heater of 0.45 lbs/hour for 3500 hours/year (amounting to 0.79 tons/year), the Division accepts the permittee's proposal of good combustion control with the emission limitation of 0.45 lbs/hour as BACT for CO emissions from the natural gas heater.

SO_2

The permittee documents that the only control technique available for natural gas heaters less than 10 MMBTU/hour is the use of low sulfur fuel and that this represents BACT for the SO_2 emissions. The Division agrees that the use of natural gas low sulfur fuel with an emission limitation of 2.0 grains/100 SCF in natural gas fuel represents BACT for the sulfur dioxide emissions from the natural gas heater.

PM/PM_{10}

The permittee documents that the most stringent particulate control method demonstrated for gas-fired heaters is the use of low ash fuel (such as natural gas). Add-on controls such as electrostatic precipitators (ESPs), or baghouses are documented to have never been applied to gas heaters smaller than 10 MMBTU/hour. The use of baghouses or ESPs is documented to be technically infeasible and that these do not represent an available control technology.

The Division accepts the permittee's proposal that use of natural gas (a low ash fuel) and good combustion control with a particulate emission limitation of 0.09 lbs/hour for 3500 hours/year (amounting to 0.16 tons/year) is BACT for particulate emissions from the natural gas heater with the limitation of 0.09 lbs/hour.

6. AIR QUALITY IMPACT ANALYSIS

Pursuant to Regulation 401 KAR 51:017, Section 12, an application for a PSD permit shall contain an analysis of ambient air quality impacts in the area that the proposed facility will affect for each pollutant that it will have the potential to emit in significant amounts as defined in Section 22 of the same regulation. The purpose of this analysis shall be to demonstrate that allowable emissions from the proposed source will not cause or contribute to air pollution in violation of:

(1) A national ambient air quality standard in an air quality control region; or
(2) An applicable maximum allowable increase over the baseline concentration in an area.

For pollutants for which no ambient air quality standard has been established, the analysis shall contain continuous air quality monitoring data gathered to determine if emissions of that pollutant will cause or contribute to a violation of the standard or a maximum allowable increase. The proposed facility will have potential emissions in excess of the significant net emission rates for nitrogen oxides, particulate/particulate-10, sulfur dioxide, and carbon monoxide.

A. Modeling Methodology

The application for the proposed source contains an air dispersion modeling analysis for criteria pollutants (nitrogen oxides, particulate/particulate-10, sulfur dioxide, and carbon monoxide) to determine the maximum ambient concentrations attributable to the proposed plant for each of these pollutants for comparison with:

1. The significant impact levels (SIL) found in 40 CFR 51.165 (b)(2).
2. The significant monitoring concentrations (SMC) found in Regulation 401 KAR 51:017, Section 24.
3. The PSD increments found in Regulation 401 KAR 51:017, Section 23.
4. The National Ambient Air Quality Standards (NAAQS) found in Regulation 401 KAR 53:010, Ambient air quality standards.

All the applicable air quality criterion are presented in Table 3. Based on the U.S. EPA suggested procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant monitoring concentrations.

Table 3

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	SMC ($\mu g/m^3$)	PSD Class II Increments ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_x	Annual	1	14	25	100
PM_{10}	Annual 24-hour	1 5	NA 10	17 30	50 150
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	20 91 512	80 365 1300
CO	8-hour 1-hour	500 2000	575 NA	NA NA	10000 40000

The permittee used the Industrial Source Complex Short Term model (ISCST3, Version 98356) in the analysis. The ISCST3 model fulfills the requirements of Supplement C of the Guideline on Air Quality Models (Appendix W to 40 CFR 51). All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. Per EPA guidance, the ISCST3 model was run with the regulatory default option in a sequential hourly mode using five consecutive years of meteorological data. Surface data and concurrent upper air data used were based on weather observations taken at the National Weather Service (NWS) station at the Paducah, Kentucky airport from 1990 to 1994. Although data for 1995 to 1997 are available, the cloud cover/ceiling height observations obtained through Automated Surface Observation System (ASOS) which became operational in August 1995, are inconsistent with the EPA meteorological processing guidelines for determining atmospheric stability, the permittee explains. Thus, this more recent data was not used.

B. Modeling results - Class II Area Impacts

The proposed facility will be located in Marshall County, a Class II area. The permittee modeled the impact of the emissions from the proposed facilities on the ambient air quality and the results of the modeled impacts on the Class II area have been presented in the Table 4.

The modeling results show (Table 4) that the maximum impacts from the proposed facility for NO_x, PM_{10}, SO_2, CO are less than the EPA prescribed significant ambient impact levels (SIL). These concentrations are also below the significant monitoring concentrations (SMC) found in Regulation 401 KAR 51:017, Section 24. Since the maximum predicted impacts for each pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS).

Therefore, no further modeling is required at this time. The applicant is also exempted from the ambient monitoring data requirements since the impacts are shown to be below the SMC. The NO_x annual average concentration for the combustion turbines is adjusted here by 700 tons per year/906 tons per year because the permittee has agreed to an annual cap of about 206 tons per year less emission (at 700 tons/year for the NO_x cap, emissions from the turbines). Even without this adjustment, the concentration is 0.47 μg/m^3, well below the SIL.

Table 4

Pollutant	**Averaging Period**	**SIL** (μg/m^3)	**SMC** (μg/m^3)	**Max Impact of CCP Emission** (μg/m^3)
NO_2	Annual	1	14	0.460
PM_{10}	Annual 24-hour	1 5	NA 10	0.063 4.740
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	0.034 2.540 17.08
CO	8-hour 1-hour	500 2000	575 NA	363.4 1293

C. Modeling Results - Class I Area Impacts

The nearest federally designated Class I area to the project site is Mingo National Wilderness Area in southeast Missouri. Mingo is 160 km west of the proposed facility the permittee documents. Mammoth Cave, Kentucky is approximately 180 km from the proposed source. Sipsey NWA is documented to be over 160 km from the source as well. Hercules-Glades Class I area in Missouri is also not within 100 km of the site. Based on the results of the dispersion analysis of the proposed project's emissions, summarized in the application Section 6.0, it is demonstrated by the permittee that the impacts of the Calvert City Power facility are less than the EPA-instituted Class I significant levels (established through the proposed New Source Review Reform regulations). Thus, the permittee documents that a comprehensive cumulative Class I increment and NAAQS analysis is not required.

The PSD regulations also require a demonstration that the proposed source's emissions would not adversely affect a Class I area's air quality related values (AQRV). Since the proposed source will be located more than 100 km from the nearest Class I area, a Class I AQRV analysis was not required of the permittee.

A table showing the concentrations at Class I area receptors and comparison with the Class I PSD significant impact levels is found below as taken from the application, Table 6-12, July 12, 1999.

Table 5

Pollutant	**Averaging Period**	**Maximum Concentration** (μg/m^3)			**PSD Class I SIL** (μg/m^3)
		Mingo NWA	**Mammoth Cave NP**	**Sipsey NWA**	
NO_2	Annual	0.0045	0.0068	0.0045	0.1
PM_{10}	24-hour	0.049	0.040	0.032	0.3
	Annual	0.0006	0.0010	0.0007	0.2
SO_2	3-hour	0.155	0.104	0.120	1.0
	24-hour	0.029	0.023	0.019	0.2
	Annual	0.0004	0.0006	0.0004	0.1

D. Modeling Results - Air Toxic Analysis

The permittee's worst case documentation of formaldehyde potential emissions, the toxic pollutant of largest quantity and of most concern pursuant to AP-42, is 3.3 tons per year based on draft AP-42 test data of a Westinghouse 520PACE turbine. The permittee explains that this test data is most representative for the proposed turbines.

Based on an emission of 3.3 tons per year of formaldehyde for 3500 hours per year, 1.886 pounds per hour emission or 0.238 grams per second results. SCREEN3 modeling results yield a maximum 1-hour ambient concentration of 0.189 μg/m^3. With the conversion from the EPA SCREEN manual of 0.08, this gives an annual average concentration of 0.015 μg/m^3. This concentration is less than the EPA Region 9 website acceptable ambient concentration of 0.093 μg/m^3. Therefore, this level of formaldehyde emissions documented by the permittee is not expected to be of concern at this time.

7. ADDITIONAL IMPACTS ANALYSIS

A. Growth Analysis

The consultant documents the following information for the proposed facility:
The Calvert City Power project will employ approximately 120 personnel during the construction phase. The project will employ approximately 8 to 12 personnel on a permanent basis. It is a goal of the project to hire from the local community where possible. There should be no substantial increase in community growth, or need for additional infrastructure. The proposed project is also not expected to result in an increase in secondary emissions associated with non-project related activities. Thus, in accordance with PSD guidelines, the analysis of ambient air quality impacts need consider only emissions from the facility itself.

B. Soils and Vegetation Impacts Analysis

The consultant documents the following information for the proposed facility:
The project lies in an area of mainly agricultural use. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. The project's potential to impact its surroundings, based on the facility's potential to emit and resulting model-predictions of maximum ground level concentrations of sulfur dioxide, nitrogen oxides, and carbon monoxide is discussed. The criteria for evaluating impacts on soils and vegetation is taken from EPA's <u>A Screening Procedure for the Impacts of the Air Pollution Sources on Plants, Soils, and Animals (EPA 1980)</u>. The Table 7-1 on p. 7-2 lists the EPA suggested criteria for the gaseous pollutants emitted directly from the proposed Calvert City Power facility and the predicted facility impacts. These criteria are established for sensitive vegetation and crops exposed to the effects of the gaseous pollutants through direct exposure. Adverse impacts on soil systems result more readily from the secondary effects of these pollutants' impacts on the stability of the soil system. These impacts could include increased soil temperature and moisture stress and/or increased runoff and erosion resulting from damage to vegetative cover. However, Table 7-1 criteria have been applied to the proposed facility to evaluate impacts on both soils and vegetation. The minimum impact level numbers in micrograms per cubic meters are not exceeded by the maximum impact concentration of the Calvert City Power project for the pollutants sulfur dioxide, nitrogen dioxide, or carbon monoxide. Therefore, it is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed facility.

C. Visibility Impairment Analysis

The consultant's information indicates that the proposed facility will comply with all requirements listed in 401 KAR 59:016 (regarding particulate and visible emissions); therefore, no significant impact to visibility within Class II area is expected to occur. On the basis of the insignificant modeling results presented in the application Section 6.0, it is also concluded that the facility will have no adverse impact on local visibility, since the significant impact levels are lower than the secondary NAAQS.

Additionally, the permittee has explained that the nearest Class I area is over 100 km away. Therefore, no further analysis was done for visibility impairment.

8. CONCLUSION AND RECOMMENDATION

In conclusion, considering the information presented in the application, the Division has made a preliminary determination that the proposed source should meet all applicable requirements:

1. All the emissions units are expected to meet the requirements of BACT for each significant pollutant. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63 will also be met.

2. Ambient air quality impacts on Class II areas are expected to be below the significant impact levels. No impact is expected on any Class I area.

3. Maximum predicted impacts of significant air toxics will be below recommended ambient air concentration levels.

4. Impacts on soil, vegetation, and visibility have been predicted to be minimal.

A draft permit containing conditions which may ensure compliance with all the applicable requirements listed above has been prepared by the Division. The Division recommends the issuance of the permit following the public notice period, and after the resolution of any adverse comments received by the Division. A copy of this preliminary determination will be made available for public review at the following locations:

1. Affected public at the Marshall County Clerk's office.
2. Division for Air Quality, 803 Schenkel Lane, Frankfort.
3. Division for Air Quality, Paducah Regional Office, 4500 Clarks River Road, Paducah.

APPENDIX C

SUMMARY OF SIMPLE CYCLE COMBUSTION TURBINE NO_x BACT DETERMINATIONS

SUMMARY OF SIMPLE CYCLE COMBUSTION TURBINE NO_x BACT DETERMINATIONS - 1995 TO PRESENT

Source	Unit Type and Size and Fuel	Model	Type of Control	NO_x BACT Level (ppm @ 15% O_2)	Hours/ year of operation	Peaking or Baseload
Tenaska Georgia Partners, L.P., GA Startup: 2003	Six 160 MW gas/oil simple cycle turbines	GE 7FA		15 ppm (gas) 42 ppm (oil)		Peaking
Southern Natural Gas, GA Startup: 2003	Four 170 MW gas/oil simple cycle turbines	GE 7FA		15 ppm (gas) 42 ppm (oil)		Peaking
Oleander Power Project, FL Startup Planned: end of 2000	Five 190 MW gas/oil-fired simple cycle turbines	GE 7FA	Dry low NO_x burners (gas) water inj. (fuel oil)	9 ppm (gas) 42 ppm (oil)	3390 (1000 or less on oil)	Probably Peaking
North Carolina Power and Light Startup Planned: Summer 2000 (2) End of 2000 (2)	Four 170 MW gas/oil-fired simple cycle turbines	GE 7FA	Dry low NO_x burners (gas) Water injection (oil)	12 ppm (gas) 42 ppm (oil)	2000	Peaking
Calvert City Power, KY (Enron) **Startup Planned: Summer 2000**	**Three 180 MW gas-fired simple cycle combustion turbines**	**One Westing-house 501F** **Two Westing-house 501FD**	**Proposed: Water injection**	**Proposed: 25 ppm**	**3500**	**Peaking**

Dynegy Reidsville, NC Startup: est. Middle 2000	Five 180 MW gas/oil-fired simple cycle turbines	Westing-house 501F	Dry low NO_x combustors (gas) Water injection (oil)	25 ppm (on gas through Apr. 1, 2001) 20 ppm (on gas from Apr. 2, 2001 to Apr. 1, 2002) 15 ppm (on gas after Apr. 2, 2002) 42 ppm (oil)	3000 (with only 1000 of the 3000 on fuel oil)	Peaking
TVA Johnsonville TN Startup: 2000	Four 85 MW gas/#2 fuel oil-fired simple cycle turbines	GE PG7121 EA	Dry low NO_x combustors (gas) Water injection (oil)	15 ppm (gas) (either 30-day or annual average) 42 ppm (oil)	30 % annual capacity factor with 1/3 of it in oil mode, 1/3 in gas peaking mode, 1/3 in gas baseload mode	Peaking
TVA Gallatin, TN Startup: 2000	Four 85 MW gas/#2 fuel oil-fired simple cycle turbines	GE PG7121 EA	Dry low NO_x combustors (gas) Water injection (oil)	15 ppm (gas) (either 30-day or annual average) 42 ppm (oil)	30 % annual capacity factor with 1/3 of it in oil mode, 1/3 in gas peaking mode, 1/3 in gas baseload mode	Peaking
Colorado Energy Managemt. Brush, CO Startup: Summer 1999	Two 25 MW gas-fired simple cycle turbines	Westing-house 1969 vintage turbines	Water injection	30 ppm (initially) 25 ppm (After two years)	4000 turbines' hours total	Peaking

Associated Electric Cooperative, MO Startup Proposed: Summer 1999	Two 100 MW simple cycle gas-fired turbines	Westing-house 501D5	Low NO_x burners	25 ppm	2000	Peaking
Colorado Springs Utilities, Nixon, CO Startup: Summer 1999	Substitute two 33 MW gas turbines for an initially proposed 110 MW due to delivery time problems	GE Frame 6B	Dry low NO_x combustors	15 ppm (@ 70% load or greater and contingent on performance testing)		Peaking
City of Lakeland, FL Startup: 4/14/99	250 MW gas/oil-fired simple cycle turbine	Westing-house 501G	Dry low NO_x (DLN) on gas, (if ultra LN on gas not able to get 9 ppm then hot SCR in 2002) water inj. on oil	25 (nat. gas until 2002) 9 ppm (nat. gas after 2002) 42 on fuel oil	8760	
Southwest-ern Public Service, NM Startup: July 1997	Two 100 MW gas-fired turbines simple cycle	Westing-house 501 D5	Dry low NO_x burner	15 ppm (w/out power augment.) 25 ppm (with power augment.)	4380 (w/out power augment.) Added 600 hrs/year with or w/out power augment.	Peaking
Empire Dist. Electric, MO Startup: est. 1996	Two 170 MW est. gas-fired simple cycle turbines (one being converted to combined cycle in near future)	Westing-house 501F	Low NO_x burners, and water inj.	25 ppm (gas)	5000	Peaking

City of Redding Electric Utility Installed: 1996	Three simple cycle gas turbines	GE Frame 5	SCR	9 ppm	550	Peaking
Gainesville Regional Utilities, FL Startup: 1995	74 MW gas-fired simple cycle turbine (oil backup)	GE frame	Dry low NO_x burners	15 ppm	3900 (up to 2000 on #2 fuel oil)	Peaking
Robins AFB, GA Startup: 1995	80 MW simple cycle gas-fired turbine (oil backup)	GE 7EA	water inj.	25 ppm	2500	Peaking
Prepa, Puerto Rico	Three 83 MW oil-fired simple cycle turbines	ABB GT 11N	steam injection and SCR	10 ppm	2000 hours/yr in “spinning reserve mode” at 581 MMBTU/hr input no limitation on baseload heat input level at 847 MMBTU/hr	
Carson Energy, in CA Startup: Fall of 1994 or 1995	One simple cycle turbine	GE LM 6000	SCR	5 ppm	3300 over 4 years	
Sempra, in CA Startup: 1994	Three (4.5-5 MW) simple cycle gas turbines	Solar	SCR	8 ppm (at steady state) 12 ppm (while in transition)		Nat. Gas com-pressor station